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Annual Report 2001

Pacific Northern Gas Ltd.

> Corporate Profile

Pacific Northern Gas Ltd. delivers natural gas to customers in west-central British Columbia, and through its subsidiary, Pacific Northern Gas (N.E.) Ltd., to customers in the province's northeast.

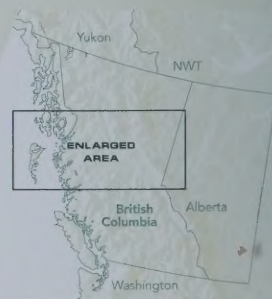
Pacific Northern's transmission pipeline is connected to the Westcoast Energy Inc. system near Summit Lake, British Columbia and extends 587 kilometres to the west coast. Service is provided to some 23 thousand customers including a number of large industrial operations. In addition, propane vapour distribution is provided in the community of Granisle.

Pacific Northern Gas (N.E.) systems serve some 16 thousand customers in the Fort St. John, Dawson Creek, and Tumbler Ridge areas. Gas supply is received at a number of locations within the Fort St. John service area. In the Dawson Creek area the Company's transmission pipeline is used to transport gas from the Westcoast Energy Inc. system. In Tumbler Ridge the Company operates its own gas processing plant.

Pacific Northern's head office is located in Vancouver, British Columbia. Customer care and administrative functions are supported from a regional centre in Terrace. In addition, personnel responsible for customer service and system construction, operation and maintenance are stationed in nine communities located within the Company's service area.

Map of Operations

- Pacific Northern Gas Mainline
- - - Pacific Northern Gas Lateral Line
- Mainline Looping
- Compressor Station
- - - Pacific Northern Gas (N.E.)
- ▲ Gas Processing Plant
- Westcoast Energy
- Communities Served



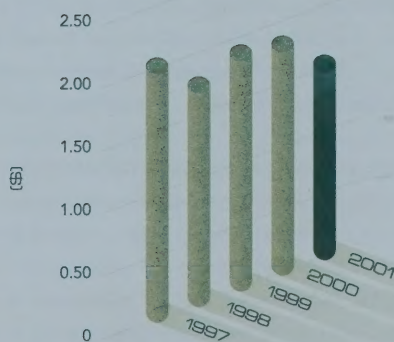
Comparative Financial Highlights

Years ended December 31	2001	2000	1999	1998	1997
Total energy delivered (TJ)	31 781	34 771	42 577	38 787	42 296
Net income (000)	\$5,715	\$6,838	\$7,125	\$6,454	\$7,926
Earnings per common share	1.52	1.83	1.92	1.73	2.16
Dividends per common share	0.00	0.56	1.12	1.10	1.00
Total investment in utility plant (000)	179,301	183,351	182,917	180,224	177,562

Business Highlights 2001

- Pacific Northern's net income was \$5.7 million in 2001, compared with \$6.8 million in 2000.
- After providing for preferred share dividends, earnings per common share in 2001 were \$1.52 compared with \$1.83 in 2000. No common share dividends were paid in 2001.
- Gas deliveries during the year totalled 31.8 petajoules, compared with 34.8 petajoules in 2000.
- Additions to property, plant and equipment totalled \$3.8 million in 2001, compared with \$7.9 million in 2000.

EARNINGS PER COMMON SHARE



➤ Report to Shareholders

Pacific Northern Gas Ltd. has faced on-going challenges in the business of transporting and delivering natural gas to remote northern communities over the past four years.

The financial results for 2001 were unsatisfactory, in spite of cost cutting initiatives achieved from the corporate reorganization in 2000 and improvements in liquidity in late 2001.

GAS PRICE VOLATILITY

Fluctuations in the commodity price of natural gas had a significant effect on our financial results in 2001. Although the Company's earnings come from the transportation and delivery, rather than the sale, of natural gas, the dramatic price increases of 2000 and 2001 have impacted customer usage and directly impacted our business of transporting natural gas. In January 2001, gas prices reached record high levels of \$14.45 per gigajoule, compared to less than \$3.00 per gigajoule in 1999.

High natural gas prices resulted in record high retail rates to customers for much of 2001. In response to the high prices as well as warmer than normal weather during the peak consumption months of January and November, many of our customers reduced their natural gas use in 2001. Some customers chose alternative fuels such as electricity and wood. In addition, economic problems in the forest industry contributed to a 1.1 percent reduction in the number of customers on the system.

As the prices for natural gas softened in mid-2001, these price decreases were passed on to customers in October 2001 and January 2002. Retail commodity prices are now approximately 27 percent below the peak 2001 levels.

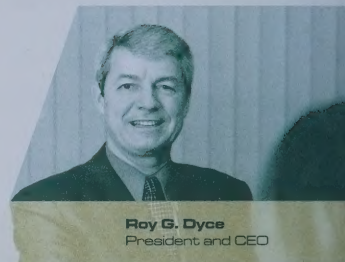
In the long-term, it is expected that demand for natural gas will remain strong. Its convenience and environmental benefits give it compelling, competitive advantages over other energy sources.

IMPACT OF 2000 REORGANIZATION

The Company's financial position has been strengthened through last year's restructuring and our efforts to reduce operating costs. We were able to achieve cost savings of \$2.4 million by closing our 11 local customer service offices and centralizing customer service in a single customer care centre in Terrace. High retail customer rates increased the call volume through the care centre, reducing response time and our ability to handle calls promptly. With two recent rate reductions in 2001 and 2002, call volumes have declined back down to expected levels.

FINANCIAL POSITION AND FLEXIBILITY IMPROVED

During 2001, the Company's financial position remained stable as we continued to focus on preserving capital and reducing operating costs. This was achieved through the continued suspension of common share dividends, combined with improved cost efficiencies and reduced capital expenditures. In addition, in November 2001, the Company completed a financing to redeem \$12 million in secured debentures that were repayable in July 2002. Scheduled debt principal repayments are now less than \$4 million per year until 2011.



KITIMAT METHANOL PLANT REOPENS

The recent reduction in natural gas prices may have a positive effect on another continuing challenge for the Company: the negotiation of long-term transportation contracts with Methanex Corporation.

Methanex, our largest industrial customer, reopened its Kitimat methanol plant in July 2001, and the plant is currently operating at normal levels. Negotiations to extend the transportation service agreements with Methanex have been underway since 1997. The Company is seeking to extend all three transportation contracts, which expire between 2002 and 2009. Any extensions depend upon the viability of the Kitimat facility and its competitive place in the global methanol marketplace, both of which remain in question.

SKEENA CELLULOSE CLOSURE

The Company lost a major industrial customer in July 2001, when Skeena Cellulose Inc. shut down its Prince Rupert pulp mill. Skeena is currently under protection from its creditors.

OUTLOOK

The continuing economic slowdown in Pacific Northern's service area has been a key factor affecting the Company's 2001 financial performance. The long-term impact of the ongoing softwood lumber dispute is also cause for concern, as the forest industry is a major employer in the region that Pacific Northern serves.

The Company's primary objective is to operate the transmission pipeline at full capacity. If a renewed contract with Methanex cannot be negotiated, the Company will intensify its efforts to find new industrial customers for this pipeline capacity.

That said, improvements in the Company's financial flexibility, along with lower gas prices, have better positioned us to move forward and take advantage of opportunities that may develop in the future.

In late 2001, an application was filed with the British Columbia Utilities Commission, the regulatory agency that approves the tolls, terms and general conditions under which the Company provides service to its customers. The application seeks Commission approval to recover, on a going forward basis, the loss in margin associated with the reduction in gas deliveries to Skeena Cellulose Inc. and a number of other customer groups. The application also asks the Commission to review the Company's business and financial risks and ensure the Company is provided an opportunity to earn a return that properly reflects these risks.

As you are no doubt aware, there has been considerable discussion during the past year by the B.C. provincial government, and to a lesser extent by the federal government, on the possible lifting of the long standing moratorium on oil and gas exploration off the Pacific Coast. There is strategic significance in development of this area as we offer an existing pipeline and a pipeline corridor that provides access to what many experts believe could be one of Canada's largest energy reserves. I can assure you we are working with the provincial government and First Nations to ensure Pacific Northern will be at the forefront of these encouraging developments.

In August 2001, the new provincial government established a Task Force to draft an energy policy framework for British Columbia. The Task Force issued an Interim Report presenting its preliminary

findings and conclusions in November 2001. The Interim Report primarily focused on the electric power sector, suggesting BC Hydro be restructured into three separate and independent operating entities – generation, transmission and distribution – and that electricity pricing move to market levels. We are encouraged with the Interim Report and remain confident that the new energy policy will be consistent with and support our efforts in promoting a gas-fired power generation unit in the Kitimat/Terrace area.

Whatever the opportunities for development, Pacific Northern is well positioned to participate as a trusted provider of reliable service. Our well maintained transmission and distribution system and dedicated organization give us a strong base for potential expansion.

The year 2001 also saw an agreement for the sale of our parent company, Westcoast Energy Inc, to Duke Energy Corporation, a multinational energy company headquartered in Charlotte, North Carolina. This sale is not expected to affect Pacific Northern's operations.

In 2001, three members of our Board of Directors retired: Roy Illing (three years), Kenneth E. Rekrutiak (six years) and Richard D. Walker (seven years). I would like to acknowledge each one of them for their contributions to Pacific Northern – your insight and guidance has been of tremendous value, thank you. I would also like to welcome Robert T. Reid, Executive Vice President and Chief Operating Officer of Westcoast Energy Inc., who joined the Board of Directors in May 2001.

In closing, I would like to thank our shareholders for their continuing support, and our employees for their perseverance and outstanding commitment to Pacific Northern Gas.



Roy G. Dyce

President and CEO

February 27, 2002.

➤ Management's Discussion and Analysis 2001

2001 FINANCIAL PERFORMANCE

Driven by high gas prices, depressed economic conditions in the Company's service area, and warmer than normal weather, Pacific Northern Gas Ltd. reported reduced income for the year ended December 31, 2001. Net income in 2001 was \$5.7 million, compared with \$6.8 million in 2000. After providing for preferred share dividends, earnings per common share were \$1.52, compared with \$1.83 in the previous year.

FINANCIAL HIGHLIGHTS

(Dollar amounts in thousands except for per share and per GJ figures)	2001	2000
Deliveries (TJ) – Sales	7 768	11 231
– Transportation service	24 013	23 540
– Total	31 781	34 771
Customers at year end	39,230	39,655
Weighted average cost of gas purchased (\$ per GJ)	\$ 6.18	4.65
Income before income taxes	\$ 11,684	12,527
Net income	\$ 5,715	6,838
Operating cash flow	\$ 15,843	18,514
EBITDA ¹	\$ 31,062	30,686
Earnings per common share	\$ 1.52	1.83

¹ Net income before interest expense, investment and other income, income taxes, depreciation, and amortization of deferred charges.

INCOME BEFORE INCOME TAXES

Income before income taxes for 2001 was \$11.7 million compared to \$12.5 million in the preceding year. The decline of \$0.8 million resulted from:

(Dollar amounts in thousands)	2001 vs 2000
Lower residential and commercial customer deliveries	(2,945)
Lower allowed return on equity	(419)
Lower operating, maintenance, administrative and general expenses, excluding company use gas	2,320
Lower capitalization of overhead expenses to plant, property and equipment	(880)
Lower interest expense	479
Other	602
Decrease in income before income taxes	(843)

Management's Discussion and Analysis (cont'd)

Operating, maintenance, administrative and general expenses totalled \$20.2 million, an increase of \$0.9 million relative to 2000. The higher expenses reflect an increase of \$2.2 million in company use gas expense, caused by higher gas commodity prices. These expense increases are offset by reductions of \$1.4 million in general operating, administrative and general expenses, net of capitalized overhead, resulting from the corporate reorganization implemented in the fourth quarter of 2000.

CONSOLIDATED QUARTERLY RESULTS (UNAUDITED)

(Dollar amounts in thousands, except for per share data)

2001

		Mar '01	Jun '01	Sep '01	Dec '01	Total
Operating revenues	\$	54,880	29,811	22,950	30,954	138,595
Net income		2,713	1,213	159	1,630	5,715
Earnings per common share – basic		0.74	0.32	0.02	0.44	1.52
Earnings per common share – diluted		0.74	0.32	0.02	0.43	1.51

(Dollar amounts in thousands, except for per share data)

2000

		Mar '01	Jun '01	Sep '01	Dec '01	Total
Operating revenues	\$	32,247	18,023	25,545	39,918	115,733
Net income (loss)		3,698	613	(53)	2,580	6,838
Earnings (loss) per common share – basic		1.02	0.15	(0.04)	0.70	1.83
Earnings (loss) per common share – diluted (restated)		1.02	0.15	(0.04)	0.70	1.83

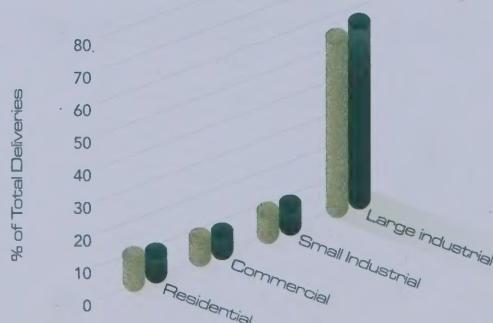
NATURAL GAS DELIVERIES

Natural gas deliveries totalled 31.8 petajoules* compared with 34.8 petajoules in 2000.

A comparison of 2001 deliveries and 2000 deliveries is provided below:

DELIVERIES IN TERAJOULES

Customer	2001	2000	% Decrease
Residential	3 470	4 216	17.7
Commercial	2 936	3 543	17.1
Small Industrial	3 592	3 875	7.3
Large Industrial	21 783	23 137	5.9
Total	31 781	34 771	8.6

**% DELIVERIES, BY
CUSTOMER CLASS**

* The joule is a metric energy measurement unit, one gigajoule (GJ) is equivalent to 0.94782 million British thermal units. One terajoule (TJ) equals one thousand GJ. One petajoule (PJ) equals one million GJ. In volumetric units, 1000 cubic metres is equivalent to 35.301 thousand cubic feet.

Management's Discussion and Analysis (cont'd)

The main reason for the significant reduction in deliveries to the residential and commercial customers is considered to be the customers' reaction to high gas prices that prevailed in late 2000 and early 2001. Many customers turned down their thermostats and many others terminated gas service in favour of using alternate fuels (primarily electricity and wood). In addition, the weather was about 1.3 percent warmer than normal with most of the warm weather occurring in the peak consumption months of January and November.

For industrial customers, demand was also impacted by ongoing depressed commodity prices as well as a slowing economy.

The small industrial customer sector reacted to the imposition of countervailing duties and anti-dumping tariffs on the lumber industry in addition to high gas prices and a depressed economy.

Deliveries to the Company's large industrial customers were mostly impacted by the shutdown of the Skeena Cellulose pulp mill in Prince Rupert in July 2001. This resulted in a decrease of about 2 467 terajoules in 2001 compared to deliveries in 2000. Offsetting this, the BC Hydro electricity generating station in Prince Rupert operated for just over half the year to take advantage of the high export electricity prices. Deliveries to BC Hydro were 1 549 terajoules higher in 2001 than in 2000. Slightly lower deliveries to Methanex also contributed to the total decrease in deliveries to the large industrial customers of 1 354 terajoules.

CUSTOMER ADDITIONS

In mid 2001 Pacific Northern implemented a modified main extension and service connection policy. These changes now require new customers to fully cover the cost of service line connections to the distribution system. Also, in situations where main extensions are required, initial customers must fund the full amount of any shortfall between the Company's allowable investment and total estimated construction costs. This has eliminated the Company's role in financing a portion of main extension costs until all anticipated customers are connected to a new main.

In 2001, 237 new customers were connected to the Company's distribution systems, compared with 428 in 2000. This decline in customer additions is the result of a number of factors. Depressed economic conditions throughout the service area resulted in a severe downturn in new construction activity. There are also few remaining candidates for conversion to natural gas in the existing building stock and limited remaining opportunity to extend gas mains into unserved rural areas.

Although some new customers were connected to the distribution systems in 2001 the Company experienced a net reduction in the number of customers served. This is a result of 672 customers leaving the distribution systems. This unusual occurrence is expected to be temporary and is predominantly a result of the dramatic increase in natural gas commodity costs which occurred throughout 2000 and early 2001. As gas commodity prices return closer to historical levels in 2002 it is likely a number of customers will return to the system.

NATURAL GAS SUPPLY

All of the Company's residential customers, most of its commercial customers and a number of its smaller industrial customers continue to rely on the Company for arrangement of their gas supply, and pay tariffs which include gas supply and service costs. The cost of gas is passed through to customers in rates and subsequent rate adjustments, after approval by the British Columbia Utilities Commission (the "Commission").

Management's Discussion and Analysis (cont'd)

Pacific Northern's larger customers typically arrange for their own firm's gas supplies and contract for transportation service on the Company's system. These customers may also purchase gas from the Company when available supply is surplus to the needs of core market customers, or arrange interruptible transportation service if capacity is available on the system.

All of the Company's gas supply is produced in British Columbia. To meet the requirements of its core market customers, natural gas is purchased under long-term, seasonal and spot contracts. Contracted gas that is surplus to the requirements of these customers may be sold either on an interruptible basis to industrial customers or sold off-system.

Natural gas is purchased at prevailing market prices and passed through to customers without any mark-up by the Company. Variances in gas purchase prices from those included in current retail rates are deferred for subsequent refund to or recovery from customers. A gas supply price risk management plan is used to manage gas supply price volatility through hedging arrangements and fixed price gas supply contracts. The 2000/2001 plan effectively moderated the overall cost of gas supply in the face of prices in December 2000 and January 2001 that were approximately four to five times greater than prices in December 1999 and January 2000. The 2001/2002 plan has resulted in fixed gas prices for a portion of seasonal gas purchased over the 2001/2002 winter period. For 2001, approximately 45 percent of gas purchases were hedged, reducing the overall cost of gas by \$6.5 million. Note 14 to the Consolidated Financial Statements provides further information as of December 31, 2001 with regard to 2002 gas supply.

Virtually all of the Company's gas supply is comprised of the pooled gas stream available from the Westcoast Energy Inc. transmission pipeline system. This includes all of the supply to the Company's transmission line serving its Western service area and approximately 75 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from Westcoast Energy, the Fort St. John system incorporates two supply interconnections with Williams Energy (Canada) Inc.'s West Stoddart Pipeline. In Dawson Creek approximately 24 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects Pacific Northern's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and the Company operates its own gas processing facilities.

A long-term contract with CanWest Gas Supply Inc. accounted for about 70 percent of 2001 purchases. Other supplies included purchases under seasonal and spot arrangements.

LARGE INDUSTRIAL CUSTOMERS

The Company has firm transportation service and interruptible sales agreements with four of its large industrial customers: Methanex Corporation ("Methanex"), Skeena Cellulose Inc. ("Skeena"), Eurocan Pulp and Paper Co. ("Eurocan") and Alcan Smelters and Chemicals Ltd. ("Alcan"). These customers produce commodities that are subject to world commodity price fluctuations. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue operation during sustained periods of low commodity prices. The Company delivers gas to its other large industrial customer, B.C. Hydro and Power Authority ("B.C. Hydro"), under an interruptible sales/service agreement for electric power generation at B.C. Hydro's facility in Prince Rupert.

Management's Discussion and Analysis (cont'd)

Methanex reopened its Kitimat methanol plant in July 2001 following the expiration of a planned twelve-month shut down that commenced in July 2000. Gas deliveries in the latter half of 2001 returned to normal levels with the Kitimat plant operating at full capacity. Deliveries to Methanex in 2001 accounted for approximately 45 percent of volumes delivered by the Company. These deliveries accounted for approximately 15 percent of the Company's operating revenues. Gas deliveries to Methanex are made pursuant to three agreements that expire between 2002 and 2009. The agreements contain minimum volume provisions, which have the effect of limiting the Company's exposure to fluctuations in gas deliveries to the Kitimat plant. The provisions require Methanex to take delivery of, or in any event pay for, a minimum level of 80 percent of contracted volumes of gas. Under an agreement between the Company and the Government of British Columbia, the Province effectively guarantees Methanex's performance under the largest contract, which expires in October 2002 and covers 77 percent of the total capacity contracted by Methanex.

Although the Company has participated over the past four years in discussions with Methanex aimed at negotiating a contract extension, agreement on a new contract has not been reached.

The Company's long-term transportation service and sales contract with Skeena matured in 1999 and is now in the third year of an evergreen one-year renewal. Skeena obtained protection from its creditors under the Companies Creditors Arrangement Act ("CCAA") in September 2001. The Provincial Government is the majority owner of Skeena and is reviewing potential offers to purchase the Company. A plan of arrangement under the CCAA is being prepared for review and approval by Skeena's creditors. The amounts owing to the Company by Skeena under the minimum take or pay obligations, totaling approximately \$1.5 million, have been deferred under an industrial customer deliveries deferral account.

The long-term transportation service and sales contracts with Eurocan and Alcan are in effect through 2004. Discussions on possible extensions of these agreements are on hold pending the final outcome of the Methanex contract negotiations. During 2001, deliveries to Skeena, Eurocan and Alcan accounted for 16 percent of the Company's total gas deliveries and 8 percent of operating revenues. BC Hydro's electric generating facility in Prince Rupert has typically been used as a stand-by facility. However, with capacity made available from the Methanex shutdown during the first half of 2001 and with attractive markets for electric power, the Company delivered 2 496 terajoules of gas to this facility in 2001.

REGULATORY ACTIVITIES

The Company's rates are determined by the Commission on a fixed rate method, under which rates are determined on the basis of forecasts of both the cost of service and throughput for the Company's transmission and distribution system. The cost of service consists of the cost of purchased gas and the cost of transporting all gas delivered through the Company's system, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base.

Rate base is the aggregate of the depreciated cost of property, plant and equipment that is used or useful in serving the public and a reasonable allowance for working capital. The Commission determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with the Company's business and the cost of capital. A revenue requirement application process leads to the implementation of new rates intended to provide the Company with the opportunity to earn an allowed rate of return on rate base.

Management's Discussion and Analysis (cont'd)

The allowed rate of return on rate base is established by first determining the weighted average cost of the individual components of the capital structure supporting the approved rate base. On a combined basis, the 2001 allowed rate of return on common equity was 9.96 percent on a deemed common equity component of rate base of 36 percent. The allowed rate of return on common equity includes a 75 basis point premium over the low risk benchmark utility rate of return (50 basis point premium for the Fort St. John/Dawson Creek division).

The revenue requirement applications for 2001 were considered by the Commission through a public hearing process for the Western transmission and distribution systems and a written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions of Pacific Northern Gas (N.E.) Ltd.

WESTERN SYSTEM

In September 2000, the Company filed an application with the Commission for approval of new rates to be effective October 1, 2000 and January 1, 2001. The Commission approved a 10 percent increase, effective October 1, 2000, to address cash flow and liquidity problems. The additional revenue collected from October to December 2000, totalling \$0.8 million, was applied to amortize existing deferral accounts in 2000.

For 2001, the Commission directed the Company to defer the difference between actual sales to Methanex, Skeena, Eurocan and B.C. Hydro and the forecast sales used by the Company in its revenue requirement application in an Industrial Customers Deliveries Deferral Account ("ICDDA"). In addition, the Commission allowed certain costs incurred by the Company relating to the restarting of the Methanex facility in Kitimat in July 2001 to be deferred in the ICDDA. The availability of the ICDDA increased 2001 operating income by \$0.9 million.

The Commission approved rate increases in 2001 that would allow for accelerated recovery of existing deferral accounts, as a response to the Methanex closure of its Kitimat methanol plant in July 2000 and the Company's liquidity problems that occurred as a result of the closure. The Commission approved accelerated recovery rates for industrial customers effective January 1, 2001, and a commercial rates restructuring charge of \$0.85 per GJ effective July 1, 2001. The additional revenue of \$1.6 million was applied in 2001 to amortize existing pipeline rehabilitation and line break deferred charges.

The Company's forecast of gas supply costs for 2001 was accepted by the Commission. Rate riders were approved for the February 1, 2001 to January 31, 2002 period to recover the debit balances recorded in the gas purchase variance recoverable account at December 31, 2000. In 2001, customer revenue from rate riders totalled \$2.8 million, which was applied, on an after tax basis, to reduce the gas purchase variance recoverable account.

In December 2000, Methanex filed an application with the Commission for a load retention rate of \$0.32 per GJ plus a factor for variable company use gas costs, effective October 1, 2000. The Commission rejected Methanex's load retention rate application in its decision rendered May 25, 2001. The Company and Methanex were unable to reach agreement on a contract extension during 2001. Methanex filed a new load retention rate application in September 2001, for rates to be effective October 1, 2001. The Commission will consider Methanex's second load retention rate application in conjunction with its review of the Company's 2002 revenue requirement application.

A rate decrease of approximately 15 percent was approved by the Commission for core market sales customers, effective October 1, 2001. The decrease resulted from lower costs being incurred by the Company to purchase gas. Gas supply prices steadily declined over the year after reaching historical highs early in 2001.

Management's Discussion and Analysis (cont'd)

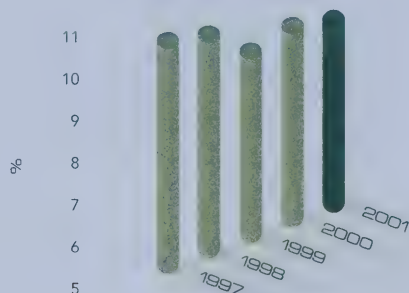
The 2002 revenue requirement application for the Western system was filed with the Commission at the end of November 2001. The application reflected adjustments to both the delivery charges and gas supply commodity charges. The 2002 forecast gas supply commodity charges were much less than what was embedded in rates effective October 1, 2001. The Commission accepted the Company's gas supply price forecast and reduced the gas supply cost commodity component of rates accordingly, effective January 1, 2002. The reduced gas costs more than offset requested increases in gas delivery charges, resulting in decreases in residential and small commercial customer rates of between 12 and 15 percent, on an interim basis.

In the revenue requirements application, residential and commercial deliveries in 2002 in the Western system are forecast to increase by approximately 6 percent compared to 2001 actual volumes, as customers are expected to respond to reductions in residential customer rates implemented in October 2001 and January 2002. The deliveries to small industrial customers are projected to be lower in 2002 by approximately 13 percent, due to difficult economic circumstances faced by industrial customers in the forestry sector. The application assumed that the Skeena Cellulose sawmills in Terrace and Smithers will remain closed in 2002. Given the continued uncertainty regarding whether Skeena will restart operations and if so, at what level, the Company has assumed in its revenue requirements application that no gas deliveries will be made to the Skeena Prince Rupert pulp mill in 2002. The application assumes the major firm service agreement between Methanex and the Company for 1 246.3 10³m³ of contract demand will not be extended past its October 31, 2002 expiry date. In its decision regarding the 2002 application, the Commission will determine the rate Methanex should then be required to pay for firm and interruptible service.

In December 2001, the Commission confirmed that its formula for determining the allowable return on common equity in 2002 resulted in a 9.13 percent return for a low risk benchmark utility for the year. For Pacific Northern, a return on equity risk premium of 75 basis points applies to the Western system resulting in an allowable return on common equity of 9.88 percent for 2002. The Company applied for approval of an increase in the equity risk premium to 150 basis points, and requested an increase in the deemed common equity component of capital structure from 36 percent to 45 percent. The Commission approved interim rates based on the lower risk premium of 75 basis points and a 36 percent deemed common equity component of the capital structure.

PNG WEST ALLOWED RETURN ON COMMON EQUITY

1997–2001



Management's Discussion and Analysis (cont'd)

The Commission is conducting a public hearing in Terrace and Vancouver during March 2002 respecting the Western system application. The Commission is expected to render a decision on the application in the second quarter of 2002.

FORT ST. JOHN/DAWSON CREEK DIVISION

The Company's forecast of gas supply costs for 2001 was accepted by the Commission. Rate riders were approved for the year 2001 period to recover the debit balances recorded in the gas purchase variance recoverable account at December 31, 2000 over a period of three years. In 2001, customer revenue from rate riders totalled \$0.9 million, which was applied, on an after tax basis, to reduce the gas purchase variance recoverable account.

Similar to the Western system, a rate decrease of approximately 15 percent was approved by the Commission for core market sales customers, effective October 1, 2001. The rate decrease was the result of lower gas prices compared to the high gas prices that prevailed in early 2001 when the gas supply cost recovery rates were set.

The Fort St. John/Dawson Creek 2002 revenue requirements application, filed in November 2001, sought Commission approval to increase the gas delivery charge component of its natural gas rates. The application requested an increase in the deemed common equity component of capital structure from 36 percent to 40 percent. The Commission approved interim rates based on the lower deemed common equity of 36 percent, resulting in an allowable return on common equity of 9.63 percent for 2002, on an interim basis. The interim rates effective January 1, 2002, resulted in rate decreases of between 13 and 15 percent for residential and small commercial customers.

The Commission is conducting a written hearing process in respect of the Fort St. John/Dawson Creek division. The Commission is expected to render a decision on the application in the second quarter of 2002.

TUMBLER RIDGE DIVISION

The Quintette mine at Tumbler Ridge was closed in August 2000, and Quintette Coal Limited ("Quintette") terminated its contract with the Company effective October 31, 2001. Under the terms of the contract, Quintette was required to reimburse the Company for the undepreciated cost of the assets purchased to service the facility. The Company received a termination payment of \$0.2 million, which was recorded as a reduction in the cost of plant assets. In addition, revenue from Quintette in 2001 exceeded the amount forecast in the 2001 revenue requirements application. As a result, \$0.3 million will be refunded to the Tumbler Ridge customers in early 2002 and this amount was recorded as a liability of the Company at December 31, 2001.

The Tumbler Ridge 2002 revenue requirement application was filed with the Commission at the end of November 2001. The application sought Commission approval to increase the gas delivery charge component of its natural gas rates and requested an increase in the deemed common equity component of capital structure from 36 percent to 45 percent, and an increase in the equity risk premium to 150 basis points. The Commission approved interim rates based on a deemed common equity of 36 percent, and the lower risk premium of 75 basis points, resulting in an interim allowable return on common equity of 9.88 percent for 2002 for the Tumbler Ridge division. The interim rates, effective January 1, 2002, resulted in rate decreases in the order of 11 to 15 percent for residential and small commercial customers.

ENVIRONMENTAL, HEALTH & SAFETY

With its 2000/2001 reorganization, Pacific Northern has been cautious not to compromise the safety of the public and its employees. Pipeline integrity continues to be an area of significant focus. All the transmission pipelines are constructed with pressure tested steel and covered with a protective coating to prevent corrosion. The Western

Management's Discussion and Analysis (cont'd)

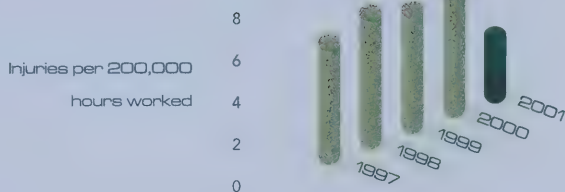
system mainline and key supply points for the Northeast have preventative alarms, which are monitored 24-hours-a-day, seven-days-a-week. The Company also conducts regular aerial and land surveillance of every kilometre of pipeline to check corrosion, leaks, vegetation, and development encroachment.

The Company strives for continuous improvement in the safe performance of all work activities. Progress was made in this area during 2001, with the Company experiencing no lost time injuries. While the frequency of motor vehicle accidents, expressed as the number of accidents per million kilometres driven, increased slightly over 2000 performance, it represents a decrease of 59 percent compared to the average rate for the previous four years. In addition, the frequency of recordable injuries decreased by 44 percent, compared to the average for the previous four years.

FREQUENCY RATE OF MOTOR VEHICLE ACCIDENTS



FREQUENCY RATE OF RECORDABLE INJURIES



ENGINEERING AND OPERATIONS

The Company continued its stress corrosion cracking investigations and repairs during the year. Some corrosion was identified in the mainline downstream from each of the Vanderhoof and Burns Lake compressor stations and the pipe was either repaired or replaced.

Management's Discussion and Analysis (cont'd)

Replacement of the original control panel for one of the compressors located at Summit Lake was completed. This programmable logic controller-based system offers more reliable control and a greater level of operational flexibility, while allowing remote access for control and troubleshooting of the compressor unit.

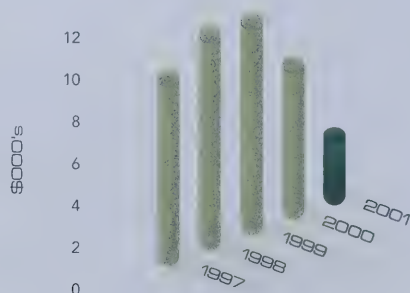
During the first half of 2001, compressor stations at Vanderhoof and Smithers were shut down and the Burns Lake compressor was operated intermittently in response to the suspension of operations at the Methanex facility and the resulting reduction in deliveries through the western transmission mainline. The restarting of the Methanex methanol plant in Kitimat in July 2001 required Pacific Northern to recommence operation of all of its compressor stations. In mid September the compressor unit at the Vanderhoof compressor station failed. A replacement unit was installed within seven days and the Company was able to maintain firm gas deliveries to all of its customers during this period.

An 18 kilometre section of Pacific Northern's original ten-inch mainline downstream from the Summit Lake compressor station was taken out of service and hydrostatically tested. This was done to ensure the integrity of this section of line, and was a follow-up to previously performed tests. The results confirmed the line's integrity and a subsequent engineering assessment is being performed to determine future testing requirements.

During 2001, the Company had a much smaller capital expenditure program than in previous years. This reduced level of capital expenditures is forecast to continue throughout 2002. Capital expenditures in 2001 totalled \$3.8 million.

CAPITAL EXPENDITURES

1997–2001



2001 marked the first year of operation of Pacific Northern's Customer Care Centre based in Terrace. The major reorganization undertaken in 2000 led to the consolidation of all routine billing functions and customer interaction into one location. Due primarily to high natural gas commodity costs, an exceptionally high in-bound call volume during the first half of 2001 created difficulty for some customers to communicate their service requirements. Call volumes moderated in the last half of the year and this trend is expected to continue. This, combined with the technological and process improvements already implemented, is expected to result in improved customer service levels in 2002.

Management's Discussion and Analysis (cont'd)

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

Cash Flow Highlights:

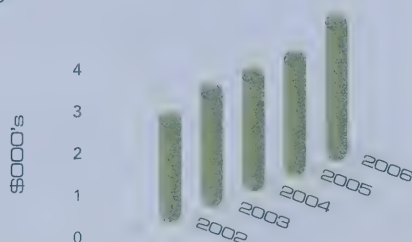
(Dollar amounts in thousands)

	2001	2000
Operating cash flow, before non-cash working capital changes	15,843	18,514
Non-cash working capital changes	5,070	8,961
Deferred charge recoveries (expenditures)	1,345	(1,713)
Additions to plant, property and equipment:		
Natural Gas Pipeline System	(1,298)	(3,957)
Processing Plant	(85)	(89)
Gas Distribution System	(2,088)	(2,352)
Other	(290)	(1,471)
Total additions	(3,761)	(7,869)
Decrease in bank indebtedness	(16,132)	(9,193)
Issue of long-term debt	12,031	—
Repayment of long-term debt	(15,326)	(3,419)
Dividends	(338)	(2,322)
Redemption of junior preferred shares	—	(1,715)
Issue of common shares	—	141
Increase (decrease) in cash	(1,268)	1,385
Cash, end of year	117	1,385

The Company has a secured demand line of credit that provides funds for general corporate and working capital requirements. In late 2001, the Company and its operating lender agreed to a reduction in the demand line of credit from \$30 million to \$20 million, subject to borrowing base requirements.

Long-term debt repayments in 2001 amounted to \$15.3 million. This includes the early redemption of all of the outstanding 10.85% 2002 Series Debentures. New long-term financing in the amount of \$12 million was issued in 2001 and used to redeem the 2002 Series Debentures. As a result of the early redemption, annual long-term debt principal repayments are forecast to remain under \$4 million until 2011.

PROJECTED LONG-TERM DEBT REPAYMENTS 2002—2006



Management's Discussion and Analysis (continued)

Reductions in capital expenditures, combined with accelerated recoveries of regulatory deferrals, cost savings realized from the corporate reorganization, and the continued suspension of common dividends through 2001, have allowed the Company to reduce its draw on the demand line of credit by more than \$25 million during the period from December 31, 1999 to December 31, 2001.

The Company's ongoing liquidity requirements will be influenced by gas prices as well as by the outcome of the Company's 2002 revenue requirements applications.

Commitments for capital expenditures in 2002 are minimal. Planned capital spending is primarily directed toward distribution mains and services and is forecast to be approximately \$5.5 million in 2002.

The Company's capital instruments are rated as follows at December 31, 2001:

	STANDARD & POOR'S	DOMINION BOND RATING SERVICE
Debentures	BB-	BB (high)
Preferred Shares	P-5 (low)	Pfd-4 (high)

RISK MANAGEMENT

OPERATING RISK

In 2001, 69 percent of energy deliveries were made to the Company's five largest industrial customers, compared to 67 percent in 2000. Four of these customers have firm gas transportation agreements expiring over the next nine years. The ongoing profitability of the Company depends on these customers continuing to take delivery of gas subsequent to the expiration of the existing contracts. The Company's ability to negotiate new contracts and to renegotiate existing contracts could be harmed by factors it cannot control, including reduced demand due for higher gas prices, the financial strength of major customers and the availability and price competitiveness of alternative energy sources.

The risk of non-performance by one or more of the large industrial customers may be analyzed and reduced, but it cannot be entirely eliminated. In addition, Pacific Northern's service area is dependent upon industrial customers, many of which are tied to the forest sector, for its economic stability. A prolonged decline in the forest and other related sectors could negatively impact deliveries to all customer classes.

While the average cost of natural gas has decreased substantially over the last eight months, the prospect of fuel-switching by customers poses a risk, as other energy sources remain cost competitive.

FINANCIAL RISK

Fluctuations in the price of natural gas could increase the working capital financing requirements and related costs for accounts receivable, and high customer rates may give rise to higher bad debt costs.

The recovery of the Company's accumulated deferral accounts is a matter of importance to its short-term financial viability and its ability to attract future financing. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval.

Management's Discussion and Analysis (cont'd)

The Company's investment activities are financed by cash generated from operations and drawings under its operating line together with proceeds from the issue of long-term debt and share capital. The uncertainty relating to the Methanex plant and volatility of natural gas prices have made it difficult for the Company to raise capital on acceptable terms.

The Company maintains insurance against exposures to the physical loss of its pipeline, compressor and other above ground facilities, as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past experience, the deductibles have increased over time and, depending on the number and severity of future outages, the financial impact on the Company could be material.

OUTLOOK

Pacific Northern's 2002 revenue requirement applications filed with the Commission in late 2001 address a number of issues of great consequence to the Company. These include: the recent and significant decline in deliveries to residential and commercial customers; the uncertainty regarding whether the Skeena Cellulose pulp mill will restart operations, and if so, at what level; the question of whether gas deliveries to the methanol/ammonia complex will be required post October 31, 2002, and if so, will it be firm or interruptible deliveries, and what will be the tolling arrangements.

The application to the Commission projects a recovery in 2002 of approximately 30 percent of residential and commercial loss in deliveries during 2001. Ultimately, a full recovery of this loss is expected, although it will be a function of the volatility and absolute level of gas prices. The outlook for natural gas prices over the next year (forward gas price strip as at February 11, 2002, for a 12-month price) is approximately 50 percent lower than the weighted average cost of gas purchased during 2001.

The application to the Commission assumes the Skeena Cellulose pulp mill and two sawmills will remain down during 2002. It is also premised on virtually no recovery in general economic conditions during 2002 throughout the Company's service area.

The Company has also requested the Commission to review Pacific Northern's business and financial risks and ensure the Company is provided an opportunity to earn a return that properly reflects the associated risks.

The Company develops a gas supply price risk management plan each year to manage gas supply price volatility through hedging arrangements and fixed price gas supply contracts. Approximately 45 percent of gas purchases in 2001 were hedged, reducing the overall cost of gas by \$6.5 million. At present the Company has no hedging arrangements in place, although approximately 34 percent of Pacific Northern's 2001-2002 winter gas requirements are under fixed price contracts, which were set in September and October 2001. The Company expects to either hedge or enter into fixed price contracts for a substantial portion of its 2002 summer gas requirements following completion of the 2002 gas supply price risk management plan.

It has always been an objective of the Company to utilize its pipeline system at the highest possible capacity level. To this end, the Company will continue to pursue a contract extension with Methanex for gas deliveries to the Kitimat methanol/ammonia complex through at least 2009.

Management's Discussion and Analysis

The Company is also encouraging the development of a gas-fired electric power generation unit in the Terrace-Kitimat area. Although only preliminary feasibility studies have been carried out, early indications of the economic viability of such a facility are promising.

Finally, the strategic significance of gas exploration off the Pacific Coast, and possibly in the Nechako and Bowser basins in west-central British Columbia, cannot be overlooked. Pacific Northern's transmission pipeline and pipeline corridor provides access to the offshore area and is in close proximity to the onshore basins.

ACCOUNTING POLICY AND DISCLOSURE CHANGES SUBSEQUENT TO 2001

In August 2001, the Canadian Institute of Chartered Accountants (CICA) approved new accounting standards for (i) Business Combinations and (ii) Goodwill and Other Intangible Assets. Goodwill and intangible assets with an indefinite life will no longer be amortized, but will be tested for impairment at least on an annual basis. Intangible assets with definite lives will continue to be amortized over their useful lives and tested for impairment when conditions indicate that carrying value may not be recoverable in its entirety. The Company will adopt the new accounting standards prospectively beginning January 1, 2002, and it is expected that adoption of the new standards will have no material effect on the Company's financial position or earnings in 2002.

In September 2001, the CICA approved new accounting standards for Stock-Based Compensation and Other Stock-Based Payments (Section 3870). The new standard encourages but does not require the use of the fair value based method of accounting, except for certain stock awards for which the fair value method must be used. Under the new standards, the fair value of a stock option is determined using an option pricing model that takes into account, as of the grant date, the exercise price, the expected life of the option, the current price of the underlying stock, its expected volatility, expected dividends on the stock, and the risk-free interest rate over the expected life of the option. The new standards apply to awards granted on or after the date of adoption. The Company will adopt the new accounting standards prospectively beginning January 1, 2002, and it is expected that adoption of the new standards will have no material effect on the Company's financial position or earnings in 2002.

In November 2001, the CICA approved new accounting guideline for hedging relationships, covering such matters as documentation, designation and the concept of effectiveness. The Company will adopt the new accounting guideline prospectively beginning July 1, 2002, and it is expected that adoption of the new standards will have no material effect on the Company's financial position or earnings in 2002.

FINANCIALS 2001

Responsibility for Financial Statements

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada and include certain estimated amounts that are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised solely of directors who are not employees of the Company or of its subsidiary. The Audit Committee meets regularly with management and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

Ernst & Young LLP, Chartered Accounts, as the Company's external auditors appointed by the shareholders, have full and free access to the Audit Committee. The Audit Committee reports its findings to the Board of Directors.

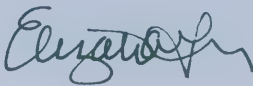
Ernst & Young LLP has performed an independent audit of the consolidated financial statements for the years ended December 31, 2001 and 2000. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report.

January 28, 2002



R.G. Dyce

President and Chief Executive Officer



E.A. Fletcher

Comptroller

Auditors' Report

TO THE SHAREHOLDERS OF PACIFIC NORTHERN GAS LTD.

We have audited the consolidated balance sheets of Pacific Northern Gas Ltd. as at December 31, 2001 and 2000 and the consolidated statements of income, retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles. As required by the British Columbia Company Act, we report that, in our opinion, these principles have been applied on a basis consistent with that of the preceding year.

Ernst & Young LLP

Chartered Accountants

Vancouver, Canada,

January 28, 2002

Consolidated Statements of Income

Years ended December 31 (Dollar amounts in thousands, except for per share data)	\$	2001	2000
Operating revenues [notes 2 and 12]		138,595	115,733
Cost of sales [note 12]		83,344	61,750
	\$	55,251	53,983
Operating and maintenance		14,834	13,711
Administrative and general		5,385	5,617
Amortization of deferred charges		2,770	1,377
Municipal and other taxes		3,970	3,969
Depreciation		7,811	7,489
	\$	34,770	32,163
		20,481	21,820
Investment and other income		136	119
	\$	20,617	21,939
Income deductions			
Interest on long term debt		7,671	8,015
Other interest		1,262	1,397
		8,933	9,412
Income before income taxes	\$	11,684	12,527
Income taxes [note 4]			
– current		10,830	(809)
– deferred		(4,861)	6,498
		5,969	5,689
Net income for the year	\$	5,715	6,838
FOR COMMON SHARES			
Net income for the year		5,715	6,838
Provision for dividends on preferred shares		338	338
Net income applicable to common shares, basic and diluted	\$	5,377	6,500
EARNINGS PER COMMON SHARE [note 6]			
Basic		1.52	1.83
Diluted [2000 – restated]	\$	1.51	1.83

See accompanying notes

Consolidated Balance Sheets

As at December 31 (Dollar amounts in thousands)

\$ 2001 2000

ASSETS [notes 7 and 8]

Current assets

Cash	117	1,385
Accounts receivable [notes 2 and 12]	21,629	28,178
Gas purchase variance recoverable	—	4,487
Income taxes recoverable	—	3,566
Inventories of supplies and natural gas	1,520	2,519
Prepaid expenses	780	922
	\$ 24,046	41,057

Plant, property and equipment [note 3]	179,301	183,351
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Deferred charges

Debt expense	797	750
Gas purchase variance recoverable	199	2,701
Pipeline rehabilitation costs	503	2,201
Other	2,267	2,229
	3,766	7,881
	\$ 207,113	232,289

See accompanying notes

On behalf of the Board:



Roy G. Dyce

Director



Arthur H. Wilms

Director

As at December 31 (Dollar amounts in thousands)

\$ 2001 2000

LIABILITIES**Current liabilities**

Bank indebtedness [note 7]	8,675	24,807
Accounts payable and accrued liabilities [note 12]	11,036	30,332
Income and other taxes payable	10,668	2,045
Long term debt due within one year [note 8]	2,650	3,326
	33,029	60,510
Long term debt [note 8]	79,539	82,158
Deferred income taxes	15,200	15,653
	\$ 127,768	158,321

Commitments and contingency [notes 3 and 14]

SHAREHOLDERS' EQUITY

Preferred shares [note 9]	5,000	5,000
Common shares [notes 10 and 11]	8,869	8,869
Contributed surplus [note 10]	2,158	2,158
Retained earnings	63,318	57,941
	74,345	68,968
	79,345	73,968
	\$ 207,113	232,289

Consolidated Statements of Retained Earnings

Years ended December 31 (Dollar amounts in thousands)	\$	2001	2000
Balance, beginning of year	\$	57,941	53,425
Net income for the year		5,715	6,838
		63,656	60,263
Preferred share dividends		338	338
Common share dividends		—	1,984
		338	2,322
Balance, end of year	\$	63,318	57,941

See accompanying notes

Consolidated Statements of Cash Flow

Years ended December 31 (Dollar amounts in thousands)	\$	2001	2000
OPERATING ACTIVITIES			
Net income for the year	\$	5,715	6,838
Add (deduct) items not involving cash:			
Deferred income taxes		(4,861)	6,498
Depreciation and amortization		10,581	8,866
Other		4,408	(3,688)
Operating cash flow		15,843	18,514
Non-cash working capital changes		5,070	8,961
Net cash provided by operating activities		20,913	27,475
INVESTING ACTIVITIES			
Additions to plant, property and equipment		(3,761)	(7,869)
Decrease (increase) in deferred charges		1,345	(1,713)
Net cash (used by) investing activities		(2,416)	(9,582)
FINANCING ACTIVITIES			
Decrease in bank indebtedness		(16,132)	(9,193)
Issue of long-term debt		12,031	—
Repayment of long-term debt		(15,326)	(3,419)
Issue of common shares [note 11]		—	141
Redemption of junior preferred shares [note 9]		—	(1,715)
Dividends paid		(338)	(2,322)
Net cash (used by) financing activities		(19,765)	(16,508)
(Decrease) increase in cash during the year		(1,268)	1,385
Cash, beginning of year		1,385	—
Cash, end of year	\$	117	1,385
Supplemental cash flow information			
Income taxes paid		681	1,216
Interest paid	\$	9,768	9,591

See accompanying notes

December 31, 2001 and 2000

Notes to Consolidated Financial Statements

Summary of Accounting Policies

ACCOUNTING PRINCIPLES

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd.

EARNINGS PER SHARE

Effective January 1, 2001, the Company adopted, on a retroactive basis, the new recommendation of the CICA with respect to the calculation and presentation of earnings per share. Under the new recommendations, the treasury stock method is used to calculate diluted earnings per share instead of the imputed interest approach. The treasury stock method assumes that any proceeds obtained upon exercise of options would be used to purchase common shares at the average market price during the period, and assumes exercise of the options only when such exercise would have a dilutive effect on earnings per share. For 2001 and 2000, application of the new recommendation increased diluted earnings per share by \$0.07 and \$0.04, respectively.

REGULATION

The Company and Pacific Northern Gas (N.E.) Ltd. are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission").

REVENUE RECOGNITION

Operating revenues include natural gas sales which are recorded on the basis of regular meter readings and

estimates of customer usage from the last meter reading date to the end of the year. Operating revenues also include transportation services revenues which are recorded as service is provided.

The Commission approved interim rates, effective October 1, 2001, that are subject to final approval in conjunction with a public hearing to be held in March 2002. The final impact, if any, of the Commission's decision on the interim rate application will be accounted for at the time of the decision.

INVENTORIES OF SUPPLIES AND NATURAL GAS

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

PLANT, PROPERTY AND EQUIPMENT

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. The cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates prescribed by the Commission. Average annual depreciation rates are 2.8% [2000 – 2.8%] for transmission plant, 2.6% [2000 – 2.6%] for distribution plant, 5.0% [2000 – 5.2%] for general plant and 4.7% [2000 – 4.8%] for processing plant. Application of these rates for the year ended December 31, 2001 resulted in a composite rate of 3.0% [2000 – 2.9%].

Notes to Consolidated Financial Statements

DEFERRED CHARGES

(A) DEBT EXPENSE

Debt expense comprises issue costs of long term debt which are amortized on a straight-line basis over the term of the related issue.

(B) GAS PURCHASE VARIANCE

RECOVERABLE

As directed by the Commission, gas purchase variance costs, which arise due to unanticipated commodity cost and demand fluctuations, are being charged to cost of sales on a straight-line basis over periods ranging from one to three years. The amount of such charges to cost of sales in 2001 was \$3,947,000 [2000 – \$1,426,000].

(C) PIPELINE REHABILITATION COSTS

As directed by the Commission, pipeline rehabilitation costs are being amortized on a straight-line basis over ten years. In 2001, pursuant to Commission approval, additional amortization of \$800,000 was taken on outstanding pipeline costs to improve the cash flow and liquidity of the Company. The total amount of amortization of pipeline rehabilitation costs in 2001 was \$1,354,000 [2000 – \$967,000].

(D) FINANCING

As directed by the Commission, in 2001 a deferral account was set up to recover costs of developing a financing plan in 2001. Total costs of \$362,000 were deferred and will be amortized commencing in 2002.

In addition, the Commission directed that the Company defer the costs associated with the early redemption of the Series 2002 Debentures in December 2001. Total costs of \$349,000 were deferred and will be amortized commencing in 2002.

The Company has applied to the Commission for a one-year amortization period for the financing and redemption deferrals.

(E) LARGE INDUSTRIAL

CUSTOMER MARGIN DEFERRAL

As directed by the Commission, in 2001 a deferral account was set up to recover the costs surrounding the reopening of Methanex Corporation's Kitimat plant, as well as the lost margin from industrial customers whose demand fell short of expectations. Total costs of \$505,000 were deferred and will be amortized commencing in 2002.

The Company has applied to the Commission for a one-year amortization period of the deferral.

(F) REORGANIZATION COSTS

As directed by the Commission, reorganization costs of \$517,000 incurred in 2000 were amortized on a straight-line basis in 2001.

(G) OTHER

As directed by the Commission, various other costs have been deferred to be recovered from future revenues over periods ranging from 1 to 5 years. During 2001, \$206,000 [2000 – \$265,000] was charged to income in respect of these deferred costs.

INCOME TAXES

The Company provides for income taxes using the income taxes currently payable method as directed by the Commission, except as described below. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items.

The Commission has directed that the deferral method of accounting for income taxes be followed for certain transactions within the Company. Under the deferral method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences

Notes to Consolidated Financial Statements

in the timing of expense deductions, are recorded as deferred income taxes.

EMPLOYEE FUTURE BENEFIT PLANS

The Company uses the pay-as-you-go method of accounting for non-pension benefits as directed by the Commission.

The Company accrues its pension obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value and obligations are now discounted using a current market interest rate.

The excess of the net unamortized cumulative actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of the plan asset at the beginning of the year is amortized over the average remaining service period of the active employees.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plan is 13 years.

For the defined contribution plan maintained by the Company, contributions payable by the Company are expensed as pension costs.

STOCK BASED COMPENSATION PLAN

The Company has one stock-based compensation plan, which is described in Note 11. No compensation expense is recognized for this plan when the stock options are issued to employees. Any consideration paid by employees on exercise of stock options is credited to share capital and contributed surplus.

FINANCIAL INSTRUMENTS

Derivative and other financial instruments are utilized in connection with management of gas supply and interest rates. The Company enters into forward, future, swap,

fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Credit risk is the risk of loss from non-performance of suppliers, customers or financial counterparties to a contract. The Company maintains credit policies which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure and monitoring of concentration of exposure to any one customer or counterparty.

COMPARATIVE FIGURES

Certain of the prior year figures have been reclassified to conform with the current year's presentation.

Notes to Consolidated Financial Statements

Major Customers

The proportion of energy deliveries and operating revenues attributable to large industrial customers is as follows:

	2001		2000	
	Energy %	Operating revenues %	Energy %	Operating revenues %
Methanex Corporation	45	15	43	19
Skeena Cellulose Inc., Eurocan Pulp and Paper Co., Alcan Smelters and Chemicals Ltd. and B.C. Hydro and Power Authority	24	10	24	12

At December 31, 2001, 20% [2000 – 14%] of accounts receivable was attributable to these five customers.

Plant, Property and Equipment

(Dollar amounts in thousands)

	\$	2001	2000
Transmission plant		174,334	173,313
Distribution plant		74,987	72,899
General plant		18,578	17,885
Processing plant		2,815	2,730
Construction in progress		560	1,335
Total plant, property and equipment	\$	271,274	268,162
Accumulated depreciation			
Transmission plant		60,075	55,779
Distribution plant		21,963	19,502
General plant		7,805	7,527
Processing plant		2,130	2,003
Total accumulated depreciation	\$	91,973	84,811
		179,301	183,351

During the year, the Company received contributions in aid of construction of \$385,000 [2000 – \$309,000], which have been recorded as a reduction of distribution plant.

Methanex Corporation ("Methanex") closed its Kitimat methanol plant on July 1, 2000 and re-opened the plant on July 1, 2001. Approximately \$36 million of the Company's net book value of plant, property and equipment and \$6 million of unrecorded deferred income taxes were incurred to service the Kitimat methanol/ammonia complex. The revenue from these contracts, expiring between 2002 and 2009, may not be sufficient to recover the costs incurred.

Notes to Consolidated Financial Statements

Plant, Property and Equipment (cont'd)

It is not possible to determine at this time whether a write down of the Company's assets will be required. The outcome is dependent upon a number of factors, including the results of regulatory rate hearings to be held in March 2002, the future prices of natural gas, the development of satisfactory arrangements for cost and financial restructuring, and the results of the Company's expenditure containment measures and business expansion activities.

Income Taxes

Significant components of the Company's deferred tax liabilities are as follows:

(Dollar amounts in thousands)	\$	2001	2000
DEFERRED INCOME TAX LIABILITIES			
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization		14,462	14,462
Other		738	1,191
Deferred income tax liabilities	\$	15,200	15,653

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

	2001	2000
Combined Canadian federal and provincial statutory income tax rates, including surtaxes (percent)	44.6	45.6
Increase (decrease) in income taxes resulting from:		
Benefit realized upon application of loss carryforwards	—	(1.8)
Large corporations tax	0.8	4.2
Depreciation in excess of capital cost allowance	6.3	2.4
Deferred charge expenditures deducted (added) for tax purposes	0.8	(5.8)
Other items	(1.4)	0.8
Effective rate of income taxes (percent)	51.1	45.4

From July 1, 1978 until its suspension on November 1, 1986, the deferral method was followed by the Company. Had the liability methodology been followed continuously since the inception of the Company, the additional deferred income tax liabilities and deferred income tax expense (recovery) would be:

(Dollar amounts in thousands)	\$	2001	2000
Deferred tax liabilities – long term, beginning of year		15,679	15,263
Deferred income tax (recovery) expense		(429)	416
Deferred tax liabilities – long term, end of year	\$	15,250	15,679

Notes to Consolidated Financial Statements

Income Taxes (cont'd)

During the year, the balance of deferred income taxes was drawn down by \$453,000 subject to approval by the Commission. Any draw down not approved by the Commission will be charged to income at the time of the Commission decision.

Pension Plans

The Company and its subsidiary have defined benefit pension plans, defined contribution pension plans and defined benefit plans providing retirement and post-employment health and life insurance benefits for most employees.

Information about the defined benefit pension plans is as follows:

(Dollar amounts in thousands)	\$	2001	2000
ACCRUED BENEFIT OBLIGATIONS			
Balance, beginning of year		11,838	12,192
Current service cost		432	549
Prior service cost		6	—
Employees' contributions		21	—
Interest cost		931	860
Benefits paid		(564)	(375)
Actuarial gains		(898)	(1,388)
Balance, end of year	\$	11,766	11,838
PLAN ASSETS			
Fair value, beginning of year		13,274	12,204
Actual return on plan assets		(4,239)	921
Employer contributions		553	504
Employees' contributions		21	20
Benefits paid		(564)	(375)
Fair value, end of year	\$	9,045	13,274
Funded status – plan (deficit) surplus		(2,721)	1,436
Unamortized net actuarial losses (gains)		2,763	(1,388)
Unamortized past service costs		5	—
Unamortized transitional asset		(20)	(18)
Accrued benefit assets	\$	27	30

Notes to Consolidated Financial Statements

Pension Plans (cont'd)

The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued benefit obligations:

	\$	2001	2000
Discount rate		7.25%	7.00%
Expected long-term rate of return on plan assets		8.50%	7.50%
Rate of compensation increase	\$	3.25%	3.25%

The Company's net defined benefit pension plan expense is as follows:

(Dollar amounts in thousands)	\$	2001	2000
Current service cost		432	536
Interest cost		931	860
Expected return on plan assets		(1,137)	(921)
Amortization of past service costs		1	—
Amortization of transitional asset		2	2
Net defined benefit pension plan expense	\$	229	477

The pension expense for the year ended December 31, 2001 and 2000 was \$382,000 and \$535,000, respectively.

Payments made during the year for non-pension benefits, which are accounted for on a pay-as-you-go basis, were \$48,000 [2000 – \$61,000]. Had the accrual methodology been followed for non-pension benefits, pension expense would have increased by \$302,000 [2000 – \$328,000].

Earnings Per Common Share

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings per common share are calculated using an adjusted average number of common shares outstanding during the year which reflect the potential exercise of dilutive share purchase options.

There are 115,920 [2000 – 132,360] stock options outstanding that could potentially dilute basic earnings per share in the future but were not included in the computation of diluted earnings per share because the options' exercise price were greater than the average market price of the common shares.

(Dollar amounts in thousands except per share data)	\$	2001	2000
Net income applicable to common shares			
– basic and diluted	\$	5,377	6,500
Weighted average number of common shares outstanding			
– basic		3,547,780	3,544,242
Effect of dilutive stock options	\$	16,361	—
Weighted average number of common shares outstanding			
– diluted		3,564,141	3,544,242
Earnings per common share			
– basic		1.52	1.83
– diluted	\$	1.51	1.83

Notes to Consolidated Financial Statements

Bank Indebtedness

(Dollar amounts in thousands)	\$	2001	2000
Bank demand operating line of credit		8,675	24,807

The Company has a bank demand operating line of credit of \$20 million [2000 – \$30 million] which bears interest at bankers' acceptance rates [December 31, 2001 – 5.23%; December 31, 2000 – 7.74%]. The line of credit is collateralized by the pledge of a \$20 million debenture and a charge on certain accounts receivable and inventories.

Long Term Debt

(Dollar amounts in thousands)	\$	2001	2000
SECURED DEBENTURES (A)			
2002 Series , 10.85% due July 15, 2002, payable in annual instalments of \$2,000,000 with a final instalment of \$12,000,000 at maturity (redeemed on December 31, 2001).		—	14,000
RoyNat Debenture due January 15, 2011, bearing interest at a floating rate [December 31, 2001 – 5.224%], payable in monthly instalments of \$110,000, with a final instalment of \$120,000 at maturity.		12,000	—
2011 Series , 10.75% due December 13, 2011, payable in annual instalments of \$700,000, and \$800,000 in each of years 2009 and 2010 with a final instalment of \$5,000,000 at maturity.		11,500	12,200
2018 Series , 8.75% due November 15, 2018, payable in annual instalments of \$600,000, commencing November 15, 1999 and \$1,000,000 in each of the years 2014 to 2017, with a final instalment of \$7,000,000 at maturity.		18,200	18,800
2025 Series , 9.30% due July 18, 2025, payable in annual instalments of \$500,000, commencing July 18, 2004 with a final instalment of \$9,500,000 at maturity.		20,000	20,000
2027 Series , 6.90% due December 2, 2027, payable in annual instalments of \$500,000, commencing December 2, 2006 with a final instalment of \$9,500,000 at maturity.		20,000	20,000
CONSTRUCTION ADVANCES AND OTHER (B)		489	484
		82,189	85,484
Long term debt due within one year		2,650	3,326
	\$	79,539	82,158

[a] Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's plant, property and equipment and gas purchases and gas sales contracts, and a first floating charge on other property, assets and undertakings.

[b] Advances have been received from certain industrial concerns to enable construction of the facilities required to provide natural gas service. This financing is non-interest bearing and will be repaid as these customers meet their commitments for the purchase of natural gas.

Notes to Consolidated Financial Statements

Long Term Debt (cont'd)

[c] Payments required to meet sinking fund and retirement provisions during the next five years are as follows:

(Dollar amounts in thousands)

		\$
2002		2,650
2003		3,079
2004		3,120
2005		3,120
2006		3,620

Preferred Shares

(Dollar amounts in thousands)

		\$	2001	2000
AUTHORIZED				
1,400,000	cumulative redeemable junior preferred shares with a par value of \$10			
200,000	6.75% cumulative redeemable preferred shares with a par value of \$25 each			
ISSUED				
200,000	6.75% preferred shares	\$	5,000	5,000

The 6.75% preferred shares are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption.

In 2000, the Company redeemed 171,573 junior preferred shares for cash consideration of \$1,715,730, resulting in nil outstanding junior preferred shares at December 31, 2000. The junior preferred shares were redeemable on a quarterly basis in amounts equal to 90% of the tax savings realized from the utilization of the non-capital loss carryforwards arising from the acquisition in 1996 of all of the outstanding shares of Centra Gas Victoria Inc., a company related through common control.

Common Shares

(Dollar amounts in thousands)

		\$	2001	2000
AUTHORIZED				
6,000,000	Class A non-voting common shares with a par value of \$2.50 each			
20,000	Class B voting common shares with a par value of \$2.50 each			
ISSUED				
3,527,780	Class A common shares		8,819	8,819
20,000	Class B common shares		50	50
		\$	8,869	8,869

Notes to Consolidated Financial Statements

Stock Option Plan

The Company has a stock option incentive plan under which share options are granted to certain of its employees. Share options are granted at an exercise price equal to the fair market value of the Company's common shares on the date of the grant.

Share options vest in five equal stages with the first stage vesting on the date of the grant, and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The maximum term of options awarded is ten years.

As of December 31, 2001, 114,580 [2000 – 217,600]

shares are reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

During 2000, the Company issued 12,120 Class A common shares for cash consideration of \$141,000 upon the exercise of employee options. Of this amount, \$111,000 has been credited to contributed surplus, representing the excess of the issue price over the par value of the shares.

A summary of the status of the Company's stock option plan as of December 31, 2001 and 2000, and changes during the years ending on those dates is presented below:

	2001		2000	
	Number of shares	Weighted- average exercise price \$	Number of shares	Weighted- average exercise price \$
Outstanding at beginning of year	132,360	20.24	131,000	20.91
Granted	107,100	7.19	28,900	15.50
Exercised	—	—	(12,120)	11.69
Forfeited	(16,440)	20.14	(15,420)	23.77
Outstanding at end of year	223,020	13.98	132,360	20.24
Options exercisable at end of year	102,032	19.15	93,160	20.27
Weighted average remaining contractual life	7.3 years		6.4 years	

Options Outstanding 2001			Options Exercisable 2001	
Expiry date	Number of shares	Exercise price \$	Number of shares	Exercise price \$
January 28, 2002	4,600	14.125	4,600	14.125
May 4, 2003	4,600	15.750	4,600	15.750
November 7, 2005	22,600	20.000	22,600	20.000
March 14, 2006	14,900	18.750	14,900	18.750
March 14, 2007	14,200	20.750	14,200	20.750
March 24, 2008	12,600	30.500	10,080	30.500
March 11, 2009	15,820	24.500	9,492	24.500
March 16, 2010	26,600	15.500	10,640	15.500
March 21, 2011	54,600	7.850	10,920	7.850
April 27, 2011	52,500	6.500	—	6.500
	223,020		102,032	

Notes to Consolidated Financial Statements

Related Party Transactions

The Company's transactions with related parties are as follows:

(Dollar amounts in thousands)

	\$	2001	2000
Westcoast Energy Inc., parent company			
Transportation services received		828	839
Materials purchases and services received		567	782
Centra Gas British Columbia Inc., a company related through common control			
Materials purchases and services received		30	24
Enlogix CIS L.P., a company related through common control			
Services received		612	582
Engage Energy Canada, L.P., an entity related through common control			
Natural gas purchases and services received		144	84
Natural gas sales		24,736	7,708

Accounts payable and accrued liabilities as at December 31, 2001 include \$243,000 [2000 – \$171,000] and accounts receivable at December 31, 2001 include \$705,000 [2000 – \$5,241,000] relating to the above related party transactions.

These transactions are in the normal course of operations and are recorded at amounts established and agreed between the related parties.

Notes to Consolidated Financial Statements

Fair Values of Financial Instruments

The fair values of debt instruments included in the consolidated balance sheets are as follows:

(Dollar amounts in thousands)		Carrying Value		Fair Value		
		2001	2000	2001	2000	
Long term debt	\$	82,189	85,484	\$	61,631	77,204

The fair value of the Company's long-term debt is estimated by reference to quoted market prices for actual or similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, gas purchase variance recoverable, income tax recoverable, bank indebtedness, income and other taxes payable, and accounts payable and accrued liabilities approximate their carrying values.

Natural Gas and Interest Rate Contracts

The Company's tolls are set using a forecasted price for gas. However, some of the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices. At December 31, 2001, the Company has entered into natural gas fixed price contracts to fix the price for approximately 1.3 billion cubic feet or 12% of its forecast 2002 system gas supply. At December 31, 2000, the Company had entered into natural gas price swap contracts to effectively fix the price for approximately 45% of its forecast 2001 systems gas supply. The difference between the price of gas used for toll purposes and the actual cost of gas purchased is deferred and refunded to or recovered from customers as directed by the Commission.

The fixed price contracts have a fair value of \$260,000 payable at December 31, 2001. The swap contracts had a fair value of \$18,960,000 receivable at December 31, 2000. The fair values reflect the estimated amounts that the Company would pay at December 31, 2001 (receive at December 31, 2000) to terminate the fixed price or swap contracts, based on the estimated future net cash flows under the terms of each contract.

Tolls for customers of Pacific Northern Gas (N.E.) Ltd. are predicated on \$8,000,000 of long-term debt financing. Accordingly, the Company is party to an interest rate swap contract that converts the interest rate characteristics of \$8,000,000 of short-term borrowings from floating to a fixed rate of 7.7% until October 2004. The swap contract has a fair value of \$798,000 payable at December 31, 2001 [\$555,000 payable at December 31, 2000]. The fair value represents the amount the Company would have to pay to terminate the swap contract at December 31, based on the quoted market prices for similar instruments.

These estimated fair market values have no impact on earnings [see also note 13] due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.



Ten Year Review

Years ended December 31 (thousands, except for per share data)

	2001	2000	1999	1998
DELIVERIES (TJ)*				
Residential	3 470	4 216	4 202	3 688
Commercial	2 936	3 543	3 108	2 897
Small Industrial	3 592	3 875	3 694	3 704
Large Industrial	21 783	23 137	31 573	28 498
Total energy delivered	31 781	34 771	42 577	38 787
Customers at year-end	39,230	39,665	39,238	38,808
Average rates per GJ*				
Residential	\$ 11.31	8.20	6.16	5.80
Commercial	10.16	5.96	4.84	4.41
REVENUE				
Residential	\$ 39,239	34,557	25,881	21,380
Commercial	29,827	21,115	15,036	12,763
Small industrial	10,539	9,349	6,356	4,912
Large industrial	33,371	36,108	29,967	31,883
Off-System	24,736	14,108	—	754
Other	883	496	498	452
	\$ 138,595	115,733	77,738	72,144
EXPENSES				
Cost of sales	\$ 83,344	61,750	24,778	20,887
Operating	24,189	23,243	22,876	20,615
Interest	8,797	9,347	9,050	9,307
Depreciation & amortization	10,581	8,866	8,094	8,322
Income taxes	5,969	5,689	5,815	6,559
	\$ 132,880	108,895	70,613	65,690
Net Income	\$ 5,715	6,838	7,125	6,454
PER COMMON SHARE				
Earnings	\$ 1.52	1.83	1.92	1.73
Dividends	—	0.56	1.12	1.10
CAPITALIZATION				
Long-term debt	\$ 79,539	82,158	85,593	88,894
Deferred income taxes	15,200	15,653	12,789	11,126
Preferred shares	5,000	5,000	6,715	10,261
Common equity	63,318	57,941	64,311	61,459
Total capitalization	\$ 163,057	160,752	169,408	171,740
Utility plant				
In service (net)	\$ 178,741	182,016	182,766	178,614
Construction in progress	560	1,335	151	1,610
Total investment in utility plant	\$ 179,301	183,351	182,917	180,224

1997	1996	1995	1994	1993	1992
3 796	3 056	2 644	2 580	2 336	1 510
3 162	2 259	2 217	2 183	2 102	1 420
2 972	2 120	1 905	1 924	1 984	1 574
32 365	30 981	27 890	31 339	31 084	29 592
42 295	38 716	34 656	38 026	37 506	34 096
37,669	27,978	26,638	25,714	24,667	17,282
5.68	4.90	5.30	5.31	5.03	5.15
4.41	3.58	4.58	4.65	4.36	4.54
21,552	14,971	14,026	13,708	11,740	7,770
13,952	9,157	10,161	10,148	9,158	6,443
4,848	3,354	4,013	3,903	3,665	2,486
35,166	33,842	30,237	34,125	32,566	32,364
1,804	1,068	2,119	—	—	—
539	431	442	442	345	246
77,861	62,823	60,998	62,326	57,474	49,309
27,295	14,975	19,943	22,281	20,390	17,302
19,877	16,611	16,518	16,527	16,143	13,096
8,903	8,822	8,915	7,918	7,781	7,504
7,067	6,792	5,646	4,969	4,420	4,136
6,793	8,238	3,785	4,030	2,777	1,868
69,935	55,438	54,807	55,725	51,511	43,906
7,926	7,385	6,191	6,601	5,963	5,403
2.16	2.01	1.67	1.80	1.63	1.48
1.00	0.96	0.94	0.88	0.88	0.80
92,135	74,862	80,056	63,990	67,937	51,875
7,119	1,863	15,514	15,731	15,703	14,877
13,609	18,910	5,000	5,000	5,000	5,000
59,142	54,785	51,038	48,432	44,787	42,020
172,005	150,420	151,608	133,153	133,427	113,772
176,103	156,995	154,421	145,047	135,187	122,999
1,459	1,244	1,929	2,590	1,789	1,028
177,562	158,239	156,350	147,637	136,976	124,027

➤ Report on Corporate Governance

The Toronto Stock Exchange ("TSE") requires that the Company disclose annually the corporate governance practices of its Boards of Directors ("Board"). Through its Corporate Governance Committee, the Board administers a program to develop and sustain suitable and effective processes and structures to guide the direction and management of the business and affairs of the Company in the pursuit of enhanced corporate performance and shareholder value. The following report addresses how the Company fulfills the principal responsibilities of a board of directors contained in the guidelines for corporate governance established by the TSE.

Board of Directors:

The Board, as set out in its terms of reference, has the responsibility for overseeing the conduct of the business of the Company and the activities of management in carrying out its responsibility for the day-to-day operations of the business. The Board acts independently of management either directly or through committees of the Board which are delegated some of the Board's responsibilities. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to ensure the Company meets its obligations on an ongoing basis in a reliable and safe manner. The Board ensures that long-term goals and a strategic planning process are in place for the Company, and that systems have been developed to monitor and manage the principal risks and potential returns associated with the business activities.

The Board is composed of seven directors. One director is a full-time officer of the Company, two directors are full-time officers of Westcoast

Energy Inc. ("Westcoast") which owns 100% of the voting common shares and is therefore considered a significant shareholder, and one director recently retired as the President and Chief Operating Officer of Westcoast and continues to provide consulting services to Westcoast. The remaining three directors do not have interests in or relationships with the Company or its parent (other than interests and relationships arising from shareholdings), which could, or could reasonably be perceived to materially interfere with such directors' ability to act with a view to the best interests of the Company. The Board has concluded that a majority of the directors of the Company are outside and unrelated.

Through the auspices of the Corporate Governance Committee, a formal assessment of the overall effectiveness of the Board is conducted annually. At the Board's encouragement, management has refined the scope and quality of information distributed to the Board. This has fostered a better understanding of all aspects of the Company's business and enhanced the effectiveness of the Board and each of its members.

The Corporate Governance Committee, which has primary responsibility for the search for and recommendation of new candidates for election to the Board, seeks to select well-qualified candidates with a diversity of background, experience and geographic location to maintain a well-balanced and highly competent group of directors with the ability to act together effectively.

Committees of the Board:

The Board has established and adopted terms of reference for each of the Audit, Executive, Environment, Health and Safety,

Compensation, and Corporate Governance Committees.

The Audit Committee is composed of outside and unrelated directors and a majority are financial professionals. One of the three committee members is a full-time officer of Westcoast. This committee is broadly responsible for ensuring that the Company's management has designed and implemented an effective system of internal financial controls, for reviewing and reporting on the integrity of the consolidated financial statements of the Company, for ensuring compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and the disclosure of material facts and for reviewing the appropriateness and effectiveness of the Company's policies and business practices which impact on the financial integrity of the Company, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management.

The Executive Committee is narrowly mandated to act as the approving body for expenditures which have been broadly approved by the Board and which are beyond the approval levels of the President and Chief Executive Officer and to perform such functions and exercise such powers as are specifically delegated to the committee by the Board. It is composed of three directors, one of whom is a full-time officer of the Company, one of whom is a full-time officer of Westcoast and another who provides consulting services to Westcoast. The Board has determined that a majority of the committee members are outside and unrelated. The Environment, Health and Safety Committee, previously the Environment Committee, is

composed of three directors, one of whom is a full-time officer of the Company. A majority of the committee members are outside and unrelated. This committee is responsible for reviewing and monitoring the policies and activities of the Company relating to environment, health and safety matters on behalf of the Board.

The Compensation Committee is composed entirely of directors who are outside and unrelated. One of the three members is a full-time officer of Westcoast. This committee is generally responsible for recommending to the Board human resources and compensation policies and guidelines for application to the Company and for implementing and overseeing human resources and compensation policies approved by the Board. In addition, it is responsible for periodically reviewing the adequacy and form of the compensation of directors and for ensuring that the compensation realistically reflects the responsibilities and risks involved in being an effective director of the Company and for reporting and making recommendations to the Board accordingly.

The Corporate Governance Committee is composed of outside and unrelated directors. One of the members of this committee provides consulting services to Westcoast. This committee's prime responsibility is to develop and monitor the Company's overall approach to corporate governance issues and to administer a corporate governance system that is effective in the discharge of the Company's obligations to its shareholders. The Committee also has the responsibility for proposing new members to the Board, establishing criteria for Board membership, recommending composition of

the Board and its committees, assessing directors' and Board performance on an ongoing basis and ensuring an orientation and education program is in place for new members of the Board.

Special Committees of the Board of Directors are struck from time to time to deal with matters of significance before the Company.

Chairman: The Board has determined that the present Chairman of the Board is an outside and unrelated director and independent of management.

Shareholder Feedback and Concerns: In conjunction with the Westcoast investor relations department, the Company maintains an active shareholder relations program. The program is designed to ensure that shareholder inquiries receive a prompt response either from the investor relations department or an appropriate officer of the Company.

Decisions Requiring Board Approval: The Board operates by seeking the advice of and delegating powers, duties and responsibilities to committees of the Board, by delegating certain of its authorities to

management and by reserving certain powers to itself. In addition to those matters which must by law be approved by the Board, the Board retains the responsibility for managing its own affairs including selecting its Chair, recommending candidates for election to the Board, constituting committees of the Board and determining director compensation.

Role of Management: Members of the management team report to the Board and its committees on a regular basis to review the Company's financial and operational results and the Company's progress in

fulfilling its strategic goals and objectives. The Board develops processes for defining its expectations of management such as reviews of the Company's strategic plan with management and a comprehensive review of the performance of the President and Chief Executive Officer, which review is carried out by the Compensation Committee.

Concluding Statement: The Company has adopted the recommendations for improved corporate governance established by the TSE.

> Corporate Information

DIRECTORS

Robert F. Chase ^{1,2,5}

President and Chief Executive Officer
Lexacal Investment Corp.
West Vancouver, British Columbia

Roy G. Dyce ^{3,4}

President and Chief Executive Officer
Pacific Northern Gas Ltd.
Coquitlam, British Columbia

Hugh C. Morris ^{1,3}

Chairman
Eldorado Gold Corporation
Delta, British Columbia

Robert F. O'Shaughnessy ^{3,5}

Company Director
Galiano Island, British Columbia

Robert T.F. Reid ^{2,4}

Executive Vice President
and Chief Operating Officer
Westcoast Energy Inc.
West Vancouver, British Columbia

Eric L. Schwitzer ¹

Senior Vice President,
Strategic Development
Westcoast Energy Inc.
West Vancouver, British Columbia

Arthur H. Willms ^{2,4,5}

Director of Westcoast Energy Inc.
North Vancouver, British Columbia

- ¹ Audit Committee.
- ² Compensation Committee.
- ³ Environment, Health and Safety Committee.
- ⁴ Executive Committee.
- ⁵ Corporate Governance Committee

OFFICERS

A.H. Willms

Chairman of the Board

R.G. Dyce

President and
Chief Executive Officer

G.B. Weeres

Vice President, Operations
& Engineering

C.P. Donohue

Director, Regulatory Affairs
& Gas Supply

D.G. Unruh

Secretary

J.M. McLeod

Treasurer

E.A. Fletcher

Comptroller

K. Stark-Anderson

Assistant Secretary

REGISTRAR & TRANSFER AGENT

Computershare Trust
Company of Canada
Vancouver, Calgary, Regina,
Winnipeg, Toronto,
Montreal

AUDITORS

Ernst & Young LLP
Vancouver B.C.

ANNUAL MEETING

The Annual Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held at the Pacific Palisades Hotel, Hastings Room, Vancouver, British Columbia on Thursday April 18, 2002 at 10:00am (local time)



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